CALIFORNIA ENERGY COMMISSION

POTENTIAL FUEL ECONOMY IN THE POST-2030 TIME FRAME

CONSULTANT REPORT

MARCH 2002
P600-02-014CR

Gray Davis, *Governor*

CALIFORNIA ENERGY COMMISSION

Prepared By:
Energy and Environmental Analysis, Inc.
1655 North Fort Myer Drive, Suite 600
Arlington, VA 22209
Contract No. 500-00-002 (WA 8A)

Prepared For:
Sherry Stoner
Contract Manager

Leigh Stamets
Project Manager

Susan Brown
Manager
Transportation Technology Office

Nancy Deller
Deputy Director
Transportation Energy Division

Steve Larson,
Executive Director

POTENTIAL FUEL ECONOMY
IN THE POST-2030 TIME FRAME

Final Report

Prepared for:
CALIFORNIA ENERGY COMMISSION
Sacramento, California

Under Subcontract to
A.D. LITTLE AND ASSOCIATES

Prepared by:
ENERGY AND ENVIRONMENTAL ANALYSIS, INC.
1655 North Fort Myer Drive
Suite 600
Arlington, VA 22209

February 2002

TABLE OF CONTENTS

Page

LIST OF TABLES

LIST OF FIGURES

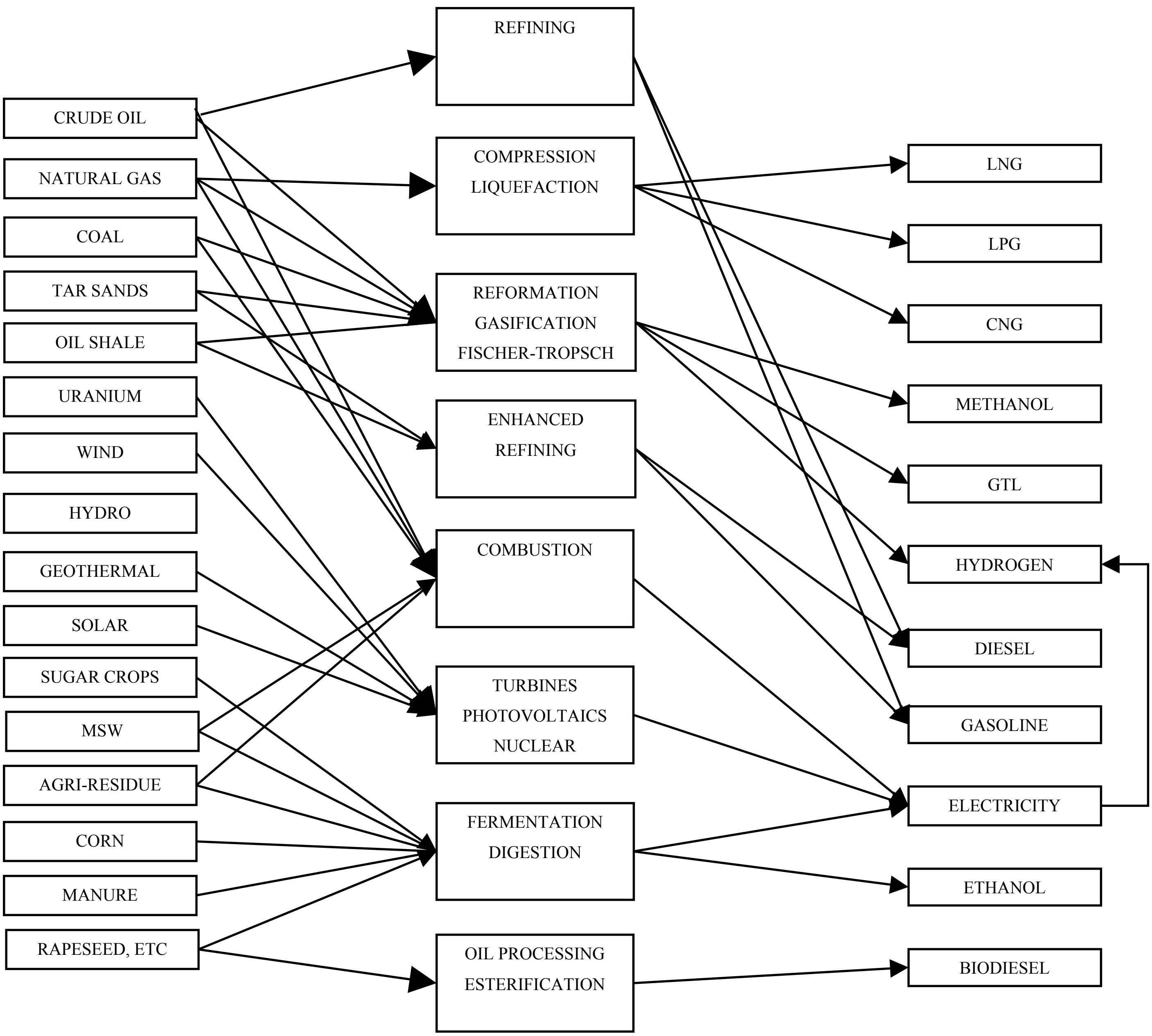
1. INTRODUCTION

This report examines fuel economy scenarios for the post-2030 time frame. Clearly, such long range forecasts are subject to a number of assumptions, and cannot be made with any great degree of certainty, and it is not the purpose of this report to provide a point forecast. Rather, it provides a unified context under which long range polices can be formulated.

Central to this question of future fuel economy are fuel prices and fuel availability. Some recent articles have suggested that the world is running out of crude oil, and that significant supply shortages and high prices could result. Of course, if fuel prices increase to $5/gallon or more, substantial increases in fuel economy will result from both technology improvement and consumer choice of smaller, less powerful and more efficient vehicles. Or the other hand, if fuel is plentiful and relatively low cost, a continuation of current trends can be expected. The unified context involves a vision of what fuels are likely to be available in the 2030 – 2040 time frame, and an estimate of a reasonable range (given current state of knowledge) of fuel prices.

The issue of fuel prices is not only related to this issue of crude oil supply, but also to the future availability of low cost alternatives. Many of these alternatives are already in the market today in limited form, while other new alternatives could emerge. In a world of crude oil at $20/bbl or less, these alternatives are clearly not price competitive now. If crude shortages develop, these alternatives could emerge as potential competitors and cap future crude price increases. In a parallel task, ADL has already examined the range of transportation fuels that could be available in the next 20 years. Figure 1-1 provides a representation of the end use fuels, and the range of potential feedstocks and processes from which they can be derived. Of these alternatives, natural gas is an obvious replacement and can be utilized directly or converted to a liquid fuel for automotive use. Hence the analysis of fuel prices in the post – 2030 time frame must also examine possible price paths for alternative fuels.

FIGURE 1-1
TRANSPORTATION ENERGY OPTIONS



Source: ADL

Section 2 examines the supply and demand for crude oil and gas, to evaluate whether either one or both fuels are likely to be supply limited in the time frame of interest (2030 – 2040). Section 3 examines the supply constraints and potential price of some of the alternatives to indicate a range of prices where alternative fuel could be competitive, providing a price cap for crude derived gasoline and diesel. Section 4 examines the implications for vehicle technology and fuel economy from the forecast range of fuel prices and alternative fuels likely to enter the market.

2. FUTURE SUPPLY OF CONVENTIONAL FUELS

2.1 OVERVIEW OF ENERGY CONSUMPTION

In 2000, 13 million barrels per day (mbpd) of petroleum products were consumed for transportation purposes in the U.S., accounting for 67 percent of all crude oil consumption in the U.S. Energy use in transportation has been growing at 1.5 to 1.6 percent over the last decade, and the growth shows no sign of abating. The rising demand for transportation energy has also been seen overseas, particularly in developing countries. For example, China's consumption of oil increased at an average rate of seven percent per annum through the 1990s. If this rate of demand growth continues for two decades (as it did in South Korea and Taiwan), China will be consuming 7.25 mbpd in the year 2006 and 14.5 mbpd in 2016. Other developing countries have been exhibiting similarly robust growth in their demand for oil. Hence, world demand is likely to increase even more rapidly than the U.S. growth rate.

Cumulative oil production to date is estimated at over 900 billion barrels, and many are concerned about how much longer current rates of production can continue. This question is difficult to answer with any certainty since technology improvements raise the amount of oil that can be extracted at a given cost, and the future state of technology is not amenable to accurate prediction. There is also significant uncertainty on the magnitude of remaining reserves of crude. The generally observed depletion pattern of non-renewable resources suggests that the production of oil from conventional sources will peak, and then decline. Some analysts have even argued that this peak of oil production has already passed and that we are now on the downward part of the production slope, while other estimates of when the peak will occur range from ten years in the future to over 100.

At present, in the U.S. natural gas is the second largest energy source. The industrial sector is the biggest consumer of natural gas, with transportation being the smallest. Once the production rate of oil slows, a gap will develop between energy supplied by oil and energy demanded. It is certainly likely that natural gas will be the substitute, but its use in vehicles has always been somewhat problematic relative to liquid fuels. However, liquid fuels from gas could play a role if they are cost competitive. Section 2.2 and 2.3 of this report examines the quantities of global oil and natural gas, the evidence that oil and natural gas production from conventional sources will peak in the 21st century, and the possible timing of these peaks.

The majority of oil consumed in the U.S. is imported, while the majority of the natural gas consumed in the U.S. is domestically produced, though imports are rising. Section 2.3 examines how a switch from oil to gas as the primary source of energy is likely to benefit the U.S. or California in terms of reducing imports.

2.2 CONVENTIONAL OIL AND RESERVES

The amount of conventional oil that remains to be economically developed is a matter of contention. The view that the world is 'running out of oil' has been receiving a lot of attention recently (see Campbell and Laherrere 1998, Edwards 1997), with Colin Campbell and Jean Laherrere, both geologists with several decades of experience in the oil industry, stating in the March 1998 issue of Scientific American that "Global production of conventional oil will begin to decline within ten years". This can be termed the pessimists' view.

The arguments rely on estimates of ultimately recoverable resources (URR) and historical production using a methodology developed by M. King Hubbert. Fitting historical production to a bell or parabolic curve, with time on the X-axis and production level on the Y-axis, enables long-term production forecasts. The area under the curve represents URR. The ongoing popularity of this approach is due in large part to Hubbert's 1956 prediction[1] of the U.S. lower 48 oil production, which turned out to be very accurate. However, this pays no attention to his other predictions, which have shown themselves to be highly inaccurate. His forecast of U.S.

---

1 Hubbert, M. King, "Nuclear Energy and the Fossil Fuels," Drilling and Production Practice,1956.

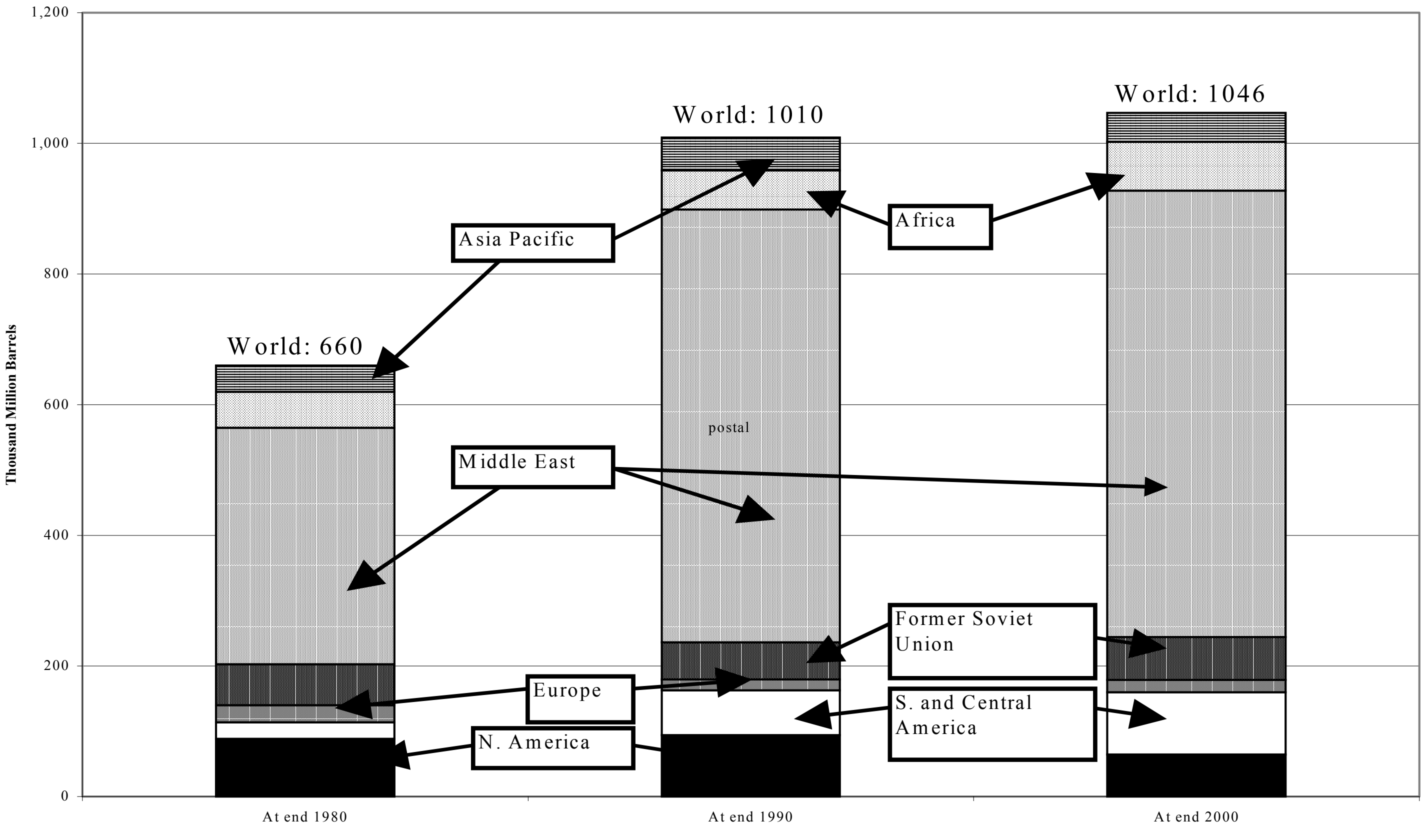
gas production in 2000 was 65 percent too low, and his world oil production forecast for 2000 was 50 percent too low.

The Department of Energy (DOE) produced a series of Hubbert-style production curves for oil in the early 1980s. The predictions for S.E. Asia have proven very accurate, but for non-OPEC S. America and Egypt, their predictions were much too low. There is an error present in these models that explains their consistently low estimates. The Hubbert model takes URR as a static variable while, as Lynch (2001) points out, it is a dynamic variable. URR refers not to total resources, which are fixed, but to the proportion of the total that is recoverable economically. Technological advances over time tend to increase the proportion of any one field that can be recovered economically. Changes in production methods that lower costs will make smaller and/or deeper fields and less productive wells economical, further raising URR. In the U.S., the success rate for exploration wells has increased by 50 percent over the last ten years. This directly increases the returns to drilling, offsetting to a degree the fall in reserve quality. In addition, if oil prices rise, more of the reserves become economic to produce, and the Hubbert methodology is problematic in a period of rising prices.

Those in the pessimist camp have defended their estimates of URR in two ways. Mackenzie (1996) argues that URR estimates have stabilized, suggesting that technology is at, or is very close to, an asymptote, so URR can be treated as now being fixed at the correct level. The basis for this assumption of technology having peaked is that the URR estimates have been converging over the past ten years. A longer-term view review of historical URR estimates, either for individual sources or the U.S. or the world, indicates that they do grow over time. Figure 2-1 illustrates the estimates of proven reserves from the British Petroleum (BP) Statistical Review of World Energy in 2001 (BP2001) by geographical region. Reserves in the U.S. have declined since 1990, but proven reserves in OPEC have increased almost 400 billion barrels, despite 20 years of production. This has further increased the proportion of world oil held by OPEC.

This trend of rising world reserves is also seen in the United States Geological Survey (USGS) survey. In 1984 the USGS world URR estimate was 1.7 trillion barrels, but by 2000 their

FIGURE 2-1
PROVEN RESERVES



Source: *BP statistical review of world energy, 2001*.

estimate had increased to three trillion bbl. Even Campbell increased his estimate from 1991 to 1997 by 150 billion barrels; this number is over and above the six intervening years of production.

Some modelers (Laherrere 1999) have argued that a final URR can be estimated by using "creaming curves", plotting the number of exploratory wells against the cumulative reserves. As the number of wells increases in a given area, the marginal increase of reserves in that area will tend to decrease (since the biggest reserves will tend to be discovered first) which seems to allow for the imputation of an asymptote. However, this is, as Lynch (2001) points out, 'like comparing acorns and oak trees'. The fact that the older fields are naturally bigger does not mean that the younger ones will continue to stay small. Rather, they are the fields that are most likely to grow over time as technology improves.

The United States Geological Survey (USGS) has produced URR estimates for the world since the early 1980s. As previously noted, in 2000 they estimated world URR at over three trillion barrels. The pessimistic camp[2] has roundly criticized the USGS assessment for being overly optimistic about technology. The USGS method, while speculative, does attempt to give a representation of the dynamic nature of technology and URR by estimating both undiscovered resources and reserve growth. USGS estimate that each of these contribute over half a billion barrels to the total URR. Reserve growth is the difference between the amount that a field is expected to finally yield now with current technology, and the amount that the field is expected to finally yield with technology in use at the time of completion. Table 2-1 provides the estimates derived by the USGS. In this table, F95 indicates that this figure is attainable with a 95 percent probability, and F5 with five-percent probability. The USGS mean estimates suggests world URR of three trillion bbl.

The pessimist camp doubts the accuracy of much of the data currently used for URR forecasts. The OECD reports official discovery data, but outside of this region the primary source for oil reserves data used by most researchers is the Oil and Gas Journal's annual survey. This data is reported by government agencies, and particularly within OPEC the numbers exhibit strange behaviors. The reserves often do not change for many years, and then fluctuate wildly for no apparent reason, frequently moving up in unison across the OPEC board. Beginning in 1985, OPEC members reported huge increases in their reserves, virtually overnight. Clearly, the large increases (300 billion barrels) in OPEC reserves reported in the late 1980s should be questioned. This is explained in part by OPEC's cartel politics, where allowances are calculated as a function of reserves, giving countries an incentive to exaggerate their reserves. It is also the case that private companies, both in and out of OPEC, face similar incentives, as greater reserves equate to a higher share price. There is no obvious method for accounting for this bias.

---

2 Campbell, Scientific American, Sept. 2000: http://www.sciam.com/2000/0900issue/0900scicit4.html and http://www.oilcrisis.com/news/article.asp?id=848

TABLE 2-1
USGS ESTIMATES OF WORLD OIL RESERVES

	BILLION BARRELS		
	F95	F5	Mean
World (Excluding U.S.)			
Undiscovered conventional	334	1,107	649
Reserve growth (conventional)	192	1,031	612
Remaining reserves			859
Cumulative production			539
Total			2,659
United States			
Undiscovered conventional	66	104	83
Reserve growth (conventional)			76
Remaining reserves			32
Cumulative production			171
Total			362
World Total (including United States)			3,012

The USGS estimates, however, do not use this public data. Rather, they actually use the same privately held data source – IHS Energy's field database – that Campbell and Laherrere used to derive their URR estimates. According to this firm, discoveries in 2000 were 14.3 billion barrels in 2000, which continues 1999's high rates of discovery (over 15 billion barrels). This has two interesting implications: first, discoveries have risen sharply in the past two years, refuting the statement that poor geology, rather than lack of access to the most promising areas, has kept discoveries low for the past three decades. The primary element behind the greater discovery rates has been the finding of two new super-giant fields in Kazakhstan and Iran. This refutes the argument that discoveries have been relatively low in recent decades due to geological scarcity and supports the optimists' arguments that the lower discoveries seen in the previous two decades were partly due to reduced prospecting in the Middle East after the 1970s nationalization of foreign oil companies.

IHS Energy makes their own estimates of remaining recoverable reserves (RRR). While EEA does not have access to their database, IHS Energy's press releases are available. RRR estimates are influenced by revisions but according to IHS Energy Group's methodology, such revisions are backdated to the time of the initial discovery. However, despite such revisions and the addition of new field discoveries, IHS Energy estimates that RRR worldwide continued to decline throughout the 1990s as annual production rose from 68.5 million billions of barrels per day (mbpd) in 1991 to 73.6 mbpd in 2000. Remaining liquid reserves now stand at 1,100 billion barrels compared to 1,207 billion barrels of reserves at the end of 1991. This compares to a figure of 1,083 billion barrels estimated by the USGS at the F95 level (not show in Table 2-1) and not including undiscovered resources. The mean estimate, however, is more than twice as large at 2,300 billion barrels, which corresponds to the figure in Table 2-1 of total-cumulative production, (i.e., 3012-171-539).

There is a wide range of estimates for URR. BP's estimate concurs with the IHS Energy URR estimate. IHS believes that the reserves-to-production Ratio (R/P) has decreased from 48 years to 41 years between 1991 and 2000. This ratio is the level of proven reserves divided by the level of consumption in that year, hence it gives an estimate of remaining years of sustainable production. Its decline indicates that the world's demand for oil continues to outpace reserve growth, and the gap between the two is widening. BP, over the period 1990 to 2000 find that it has fallen from 43 to 40, see Figure 2-2. While the R/P ratio is declining, it is not declining as rapidly as expected due to the continuing pace of discoveries. Indeed, the R/P ratio in 2000 is higher than the ratio in 1980.

2.3 TIMING OF THE OIL PRODUCTION PEAK

The Energy Information Administration (EIA) has estimated the timing of peak oil production using the USGS high, low and medium URR estimates together with rates of increase in global oil production of between 0 percent and three percent. The forecast for each of these combinations is displayed in Figure 2-3. Here the 'HIGH' refers to the highest USGS estimate of URR, which 3,896 billion barrels, 'LOW' refers to their lower boundary estimate of 2,248 billion barrels, while 'MEAN' is the statistical mean of their estimates, 3,003 billion barrels. (Note that 700 billion bbl have been already produced of the 3 trillion barrels.) The methodology is simplistic since both supply and demand need to be considered simultaneously, but is useful to illustrate the time periods to possible production peaks.

FIGURE 2-2
RESERVE/PRODUCTION RATIO OVER TIME

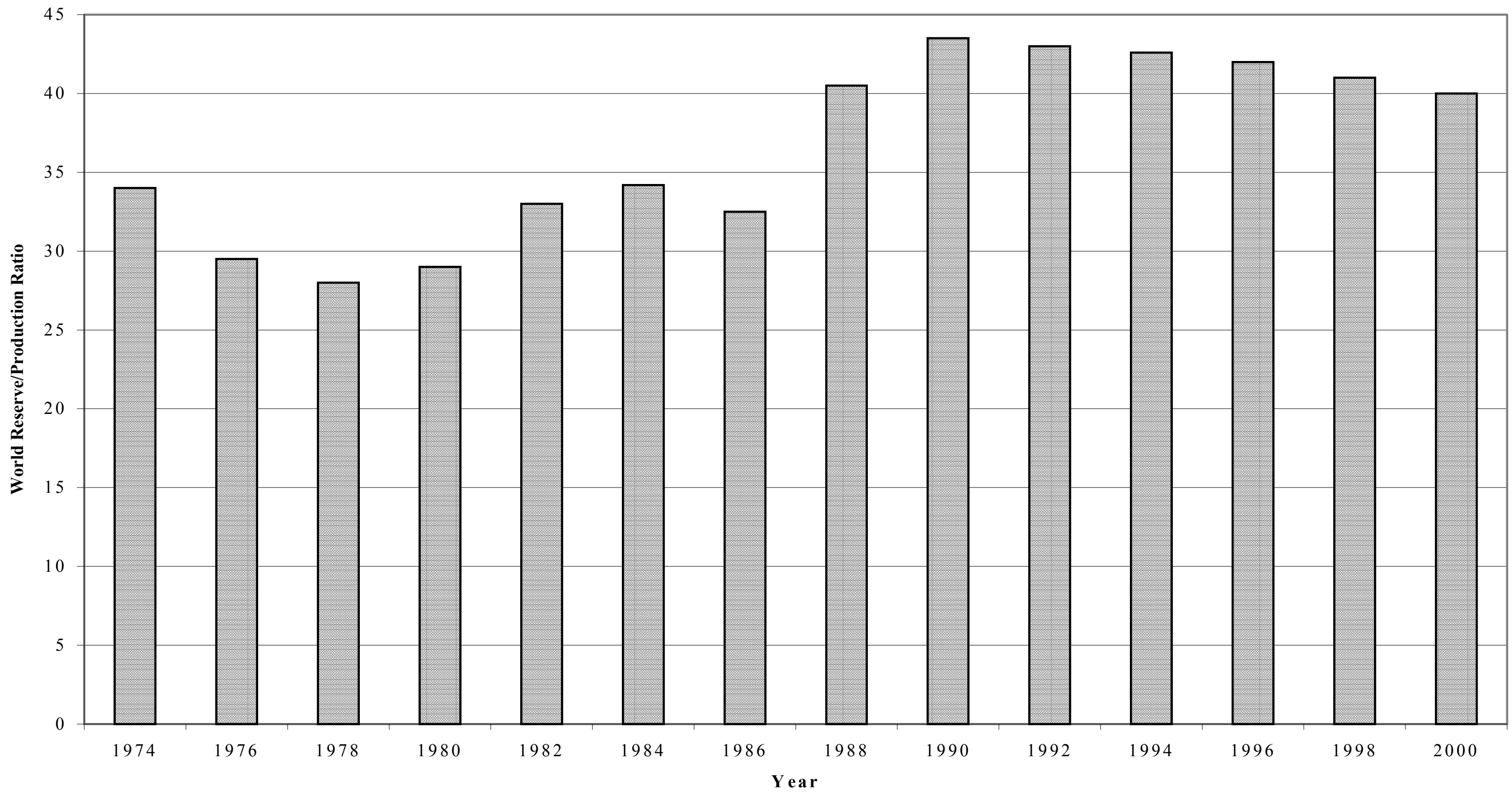
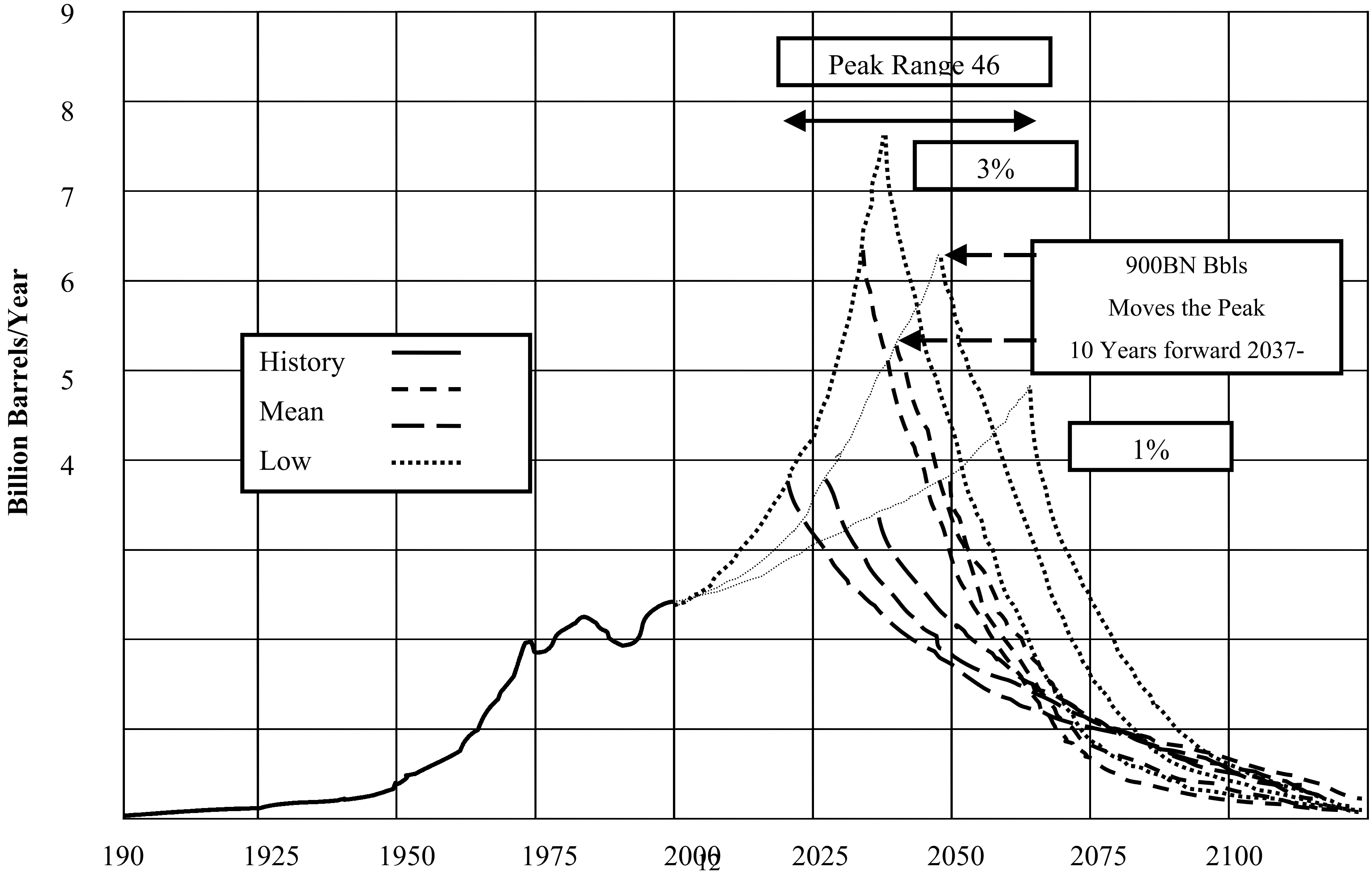


FIGURE 2-3
EIA ESTIMATES OF PEAK PRODUCTION GIVEN VARIOUS URR AND OIL PRODUCTION RATES
Source : EIA, Long Term Oil Supply Presentation



The different sets of curves in Figure 2-3 represent the production paths that may result from different combinations of URR and oil production growth rates. For example, an annual one percent increase in oil consumption combined with the high USGS URR estimate of 3,896 billion barrels results in a production peak in 2067. The same URR with an annual increase in oil production of two percent results in a production peak in 2050. In reality, prices will increase as production declines, which in turn will reduce demand and eventually increase production. Hence, production may see multiple peaks due to the lag time to equilibrate the market.

World oil consumption has been increasing by an average rate of 2.2 percent per year since 1993[3], which indicates that if the mean USGS estimate of URR is correct, then a peak of oil production will occur somewhere in the 2030 – 2040 time frame. If the high URR estimate is accurate, then the peak is reached in the 2037 – 2047 period. The increase of 900 billion barrels in reserves delays the production peak by about ten years. The worst case scenario, according to the EIA estimates, is a three-percent growth rate and a lower bound USGS URR, which would result in a peak in about 2020.

A production peak in 2035 (mid case) followed by a continual decline, coupled with a demand that continues increasing at a rate of two percent, could result in a gap between demand and production of around 50 billion barrels of oil equivalent (145 million barrels pre day) by 2050. This is almost twice the current level of conventional oil production. The available data suggests that the most likely occurrence under the stated assumptions of a production peak will be in the 2035 time frame, which coincides with the time frame of interest. While crude oil production from conventional reserves could peak in that time frame, there are "non-conventional" sources of crude such as tar sands, oil shale, etc., that are considered below.

Oil Sands/Tar Sands

Oil sands (also known as tar sands) contain oil in huge quantities (trillions of barrels), particularly in Alberta, Canada and Venezuela. Oil sands can either be mined, or recovered by a technique referred to as Steam Assisted Gravity Drain (SAG-D) in which steam is injected into the upper of two parallel pipes and the oil is collected in the lower pipe. The oil must have lighter hydrocarbons added to it to allow it to flow and be processed into conventional petroleum products. Heavy oil sand deposits can be injected with hot water or steam. Because of the energy that these processes require, net energy recovery is less than is the case with conventional oil resources.

At present about 500,000 barrels a day are recovered from the Athabasca oil sands in Alberta. In the early 1980s, Syncrude's operating costs were around $19 a barrel. Last year they were just over $8. Albian Sands is projecting costs of between $6 and $7 a barrel, and Suncor's new Project Millennium between $5.40 and $6[4]. Once the resource, conversion, waste disposal and shipping costs are added, then this source of oil is competitive with crude even at the current $20 per barrel price.

Analysts[5] have stated that it may be possible to increase this ten-fold, to five million barrels a day, but only at significant environmental cost. These five million barrels could amount to about seven percent of the 76 million barrels consumed daily worldwide at present, or about 30 percent of U.S. consumption.

Shale Oil

There is a common saying in the industry that shale oil is 'the fuel of the future, and always will be.' The shale has to be mined, heated to about 450 C and have hydrogen added to the product to make it flow. The shale expands upon heating, which causes both the volume/energy ratio to be low and a problem with waste disposal. Net energy recovery is low. It takes several barrels of water to produce one barrel of oil, while the world's largest shale deposits are in the Colorado plateau, a markedly water poor region.

---

3 Birkey et al. (2001)

4 National Post newspaper, July 9th, 2001

5 YOUNGQUIST, W., 1998, "Shale Oil--The Elusive Energy" Hubbert Center Newsletter, 98/4: http://www.hubbertpeak.com/youngquist/altenergy.htm.

The aspect of shale oil that warrants the attention it receives is its abundance. Estimates of the volume of potential oil in the U. S. shale deposits have grown steadily since they were first studied in detail by the USGS in the early 1900's. Duncan (1981)[6] states "The oil shale deposits of the United States can be considered collectively as an enormous low-grade source of oil, hydrocarbon gas, or solid fuel. Deposits with an estimated yield of ten gallons or more oil per ton of rock contain more than 2 trillion barrels; their possible extensions may contain an additional three trillion barrels; and, speculatively, other unappraised deposits may contain several times as much oil." However, production cost estimates suggests that it will not be competitive until crude costs are well in excess of $40/bbl.

2.4 NATURAL GAS RESERVES AND PRODUCTION

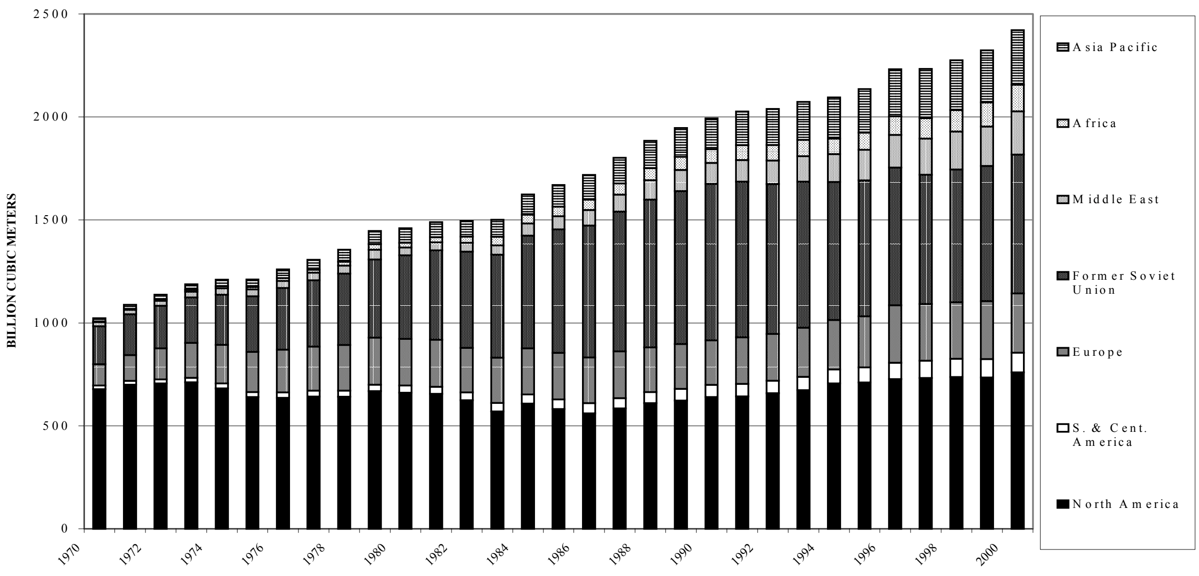
Natural gas is presently the world's second biggest energy source after oil. The expanding production of natural gas in recent years (see Figure 2-4) reflects the more than doubling of proven global gas reserves since 1980 and the expansion of markets for gas over the period since 1990. Natural gas has entered the 21st century with an R/P ratio of over 60 years. This ratio indicates that the expansion of production in the early decades will continue to be demand limited, rather than resource supply-constrained. Indeed, the reserves of already discovered fields could in themselves serve to keep global gas production growth at over three percent per annum until 2025, location and demand permitting. Large additional discoveries are expected with great confidence within the industry, given the geographically broadening base of exploration coupled with the more intensive exploitation of existing gas-rich provinces, including some areas that were thought to be mature (e.g., in the Gulf of Mexico and the North Sea).

The increasing levels of production seen over the last thirty years have been greatly outpaced by the rate of discoveries. Figure 2-5 displays the proved reserves by region according to BP (Note that Figure 2-4 is scaled in billions of cubic meters, while Figure 2-5 is scaled in trillions). The USGS, assuming that technology will continue to progress over time, assessed total conventional gas resources at 385 trillion cubic meters, which represents 158 years of production at the current rate of production.

---

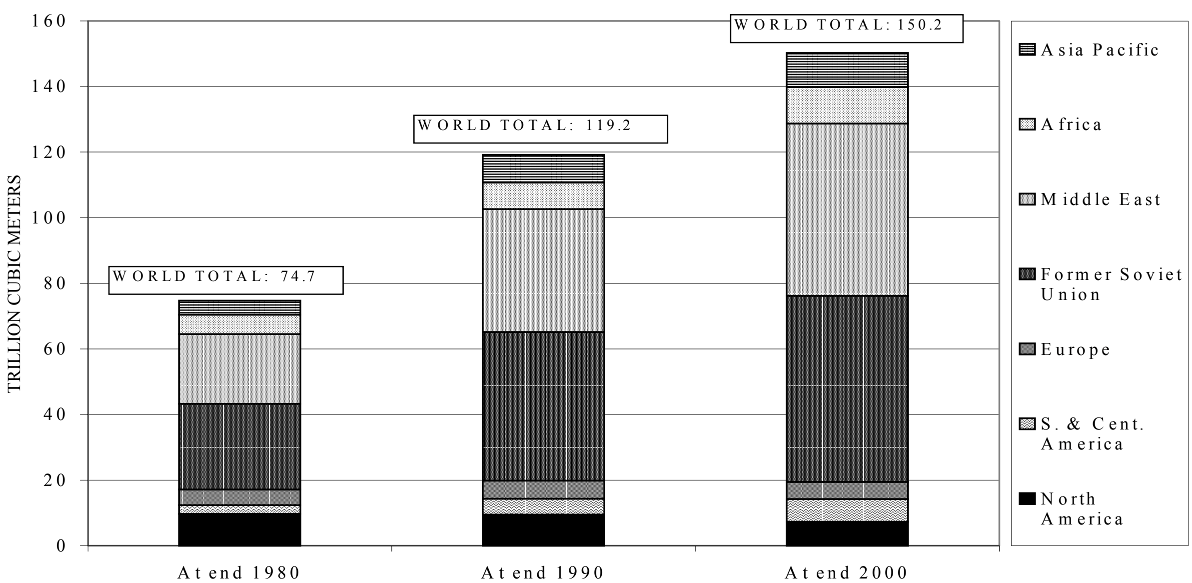
[6] Oil Shale: A Potential Source of Energy (pamphlet issued for general public information), USGS.

FIGURE 2-4
WORLD GAS PRODUCTION BY REGION



Source: BP Statistical Review of World Energy, 2001

FIGURE 2-5
PROVED NATURAL GAS RESERVES BY REGION



Source: BP Statistical Review of World Energy, 2001

A 1993 EEA assessment of gas reserves[7] found that while a great deal of gas was available, nearly all of the low cost gas was in the Middle East. The study calculated costs of producing gas from the world's undeveloped, non-associated reserves in order to determine the potential supply of methanol produced from natural gas[8]. Gas fields in 32 countries containing 90 percent of the world's proven gas reserves were individually examined. The costs of development for each field were estimated using standard economic assumptions. Of the 2,065 tcf of eligible gas identified, 665 tcf was estimated to be available at less than $1/Mmbtu. Of this over 80 percent was located in Iran, Qatar and Saudi Arabia. While the former Soviet Union does have vast gas reserves, only 9 tcf were estimated to be accessible at below $1/Mmbtu, mainly because of the high transportation costs from remote Siberian locations.

Non-Conventional Gas Reserves: Methane Hydrates

Methane hydrates form when methane gas dissolves and forms crystals in icy cold waters at the sea bottom. When exposed to warm temperatures and sea level atmospheric pressures, these methane gas hydrates expand to 164 cubic meters of methane and 0.8 cubic meters of water. There is a lot of work being done on this prospective energy source; Argonne Labs estimate the recovery of methane from hydrates using current technology results in a cost of approximately $6 Mmbtu[9] (vs. $2 on average at present). For methane hydrates to become economical will take great technological progress. However, these hydrates have the potential to be an enormous energy source. Global methane hydrate reserves are estimated to be about 137 trillion barrels of oil equivalent (Rogner, 1997).

2.5 SIGNIFICANCE FOR THE U.S. AND CALIFORNIA

There is substantial evidence that global oil production could peak in the early 21st century, and will then decline. The peak for natural gas production will be substantially later, almost certainly beyond 2050 and potentially not until the 22nd century. A possible peak of oil production between 2030 and 2040 followed by a downturn in supply raises the prospect of a significant gap

---

7 "Development Costs of Undeveloped Non-associated Gas Reserves in Selected Countries," DOE/EP- 003P, Technical report.
8 EEA 1993
9 http://www.es.anl.gov/htmls/cbt13-methane.html

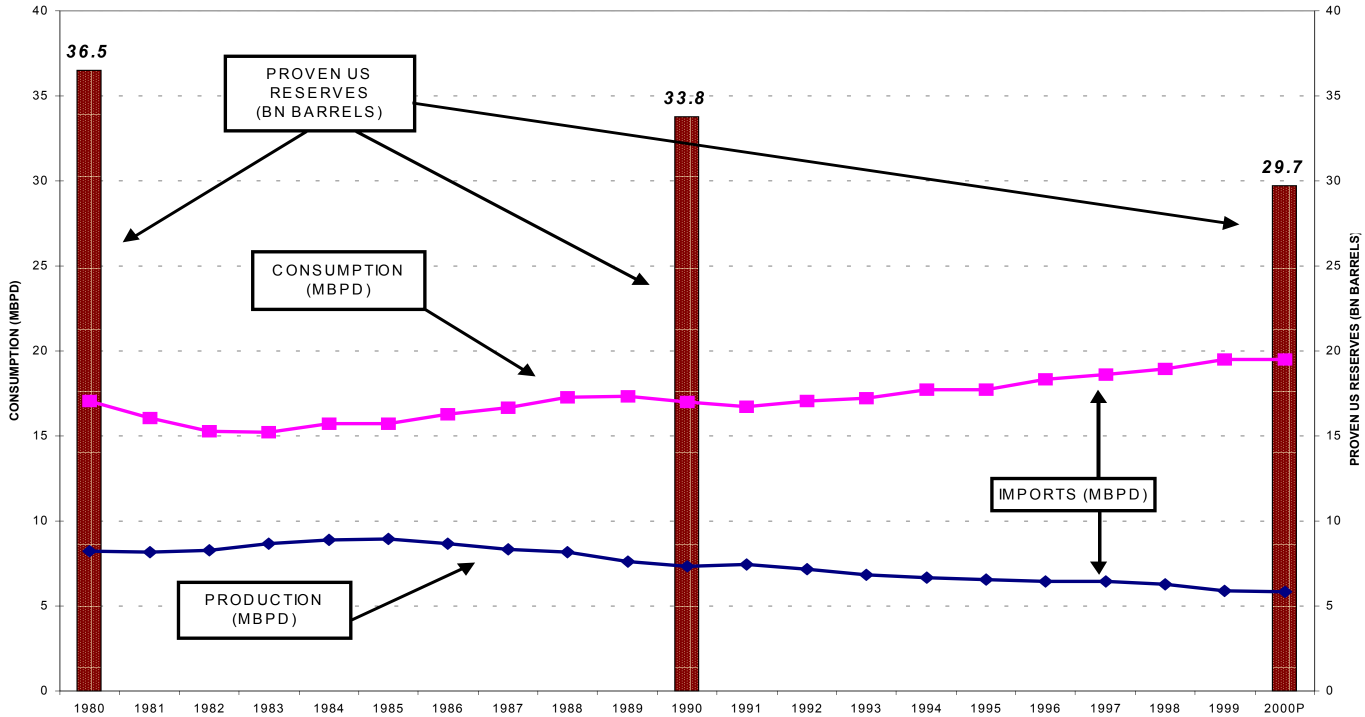
arising between the demand for energy and the amount that can be economically supplied by oil. Hence, oil price increases are inevitable in this time frame.

Figure 2-6 displays the production, consumption and proven reserves in the U.S. over the past twenty years. Several trends are apparent. Proven reserves and production levels in the U.S. have been falling, while consumption has been rising. Since 1998, over half of the petroleum used by the U.S. economy has been imported. This rise in demand has been fuelled by the steady growth in demand from the transportation sector combined with the ongoing depletion of domestic reserves. Global oil production has yet to peak, while U.S. domestic production has been in almost continuous decline since 1970.

Figure 2-7 displays the decline that has been seen in total U.S. crude production as well as the decline in individual well productivity. This decline has been occurring at the same time as the very strong growth in demand for petroleum from the transportation sector, which explains the growth in oil imports. Oil imports amounted to $60 billion in 1999, equal to 18 percent of the U.S. trade deficit. In 2000 oil imports were 25 percent of the trade deficit. Domestic oil production presently stands at about 5.9 mb/d, far below its 1970 peak of over 9 mb/d. There is every indication that all of these trends will continue: Demand from transportation will continue to grow, domestic reserves and production will continue to decline and hence imports will continue to increase.

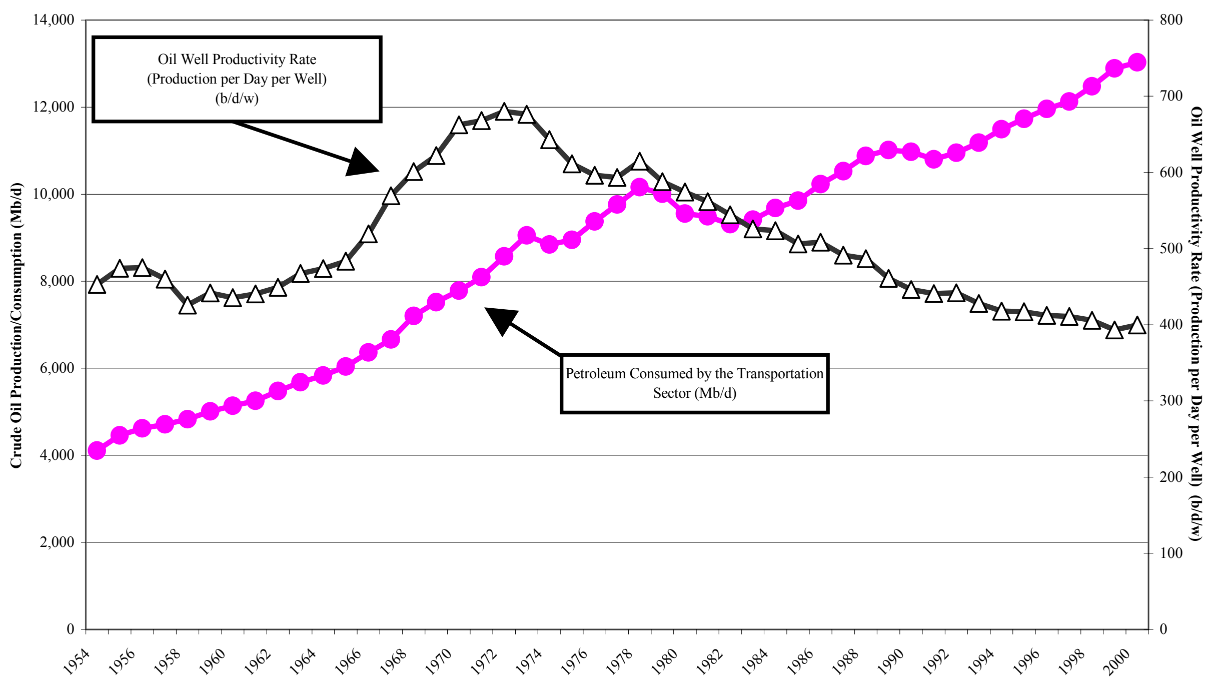
In the wake of the oil crisis in the early 1970s key sectors of the U.S. economy (utilities, commercial and residential) successfully made a complete or at least substantial switch away from petroleum as their prime energy source. Transportation, however, has remained almost completely dependent on oil. The U.S. consumes about 25 percent of world oil, with approximately 13 mb/d being used for transportation. Light vehicles use 60 percent (8 mb/d) of this. U.S. light and heavy vehicles together account for 47 percent of the oil consumed by on-road vehicles worldwide.

FIGURE 2-6
PRODUCTION, CONSUMPTION AND PROVEN RESERVES IN THE U.S.



Source: EIA Annual Energy Report 2000

FIGURE 2-7
THE DECLINE IN U.S. CRUDE PRODUCTION AND WELL PRODUCTIVITY.



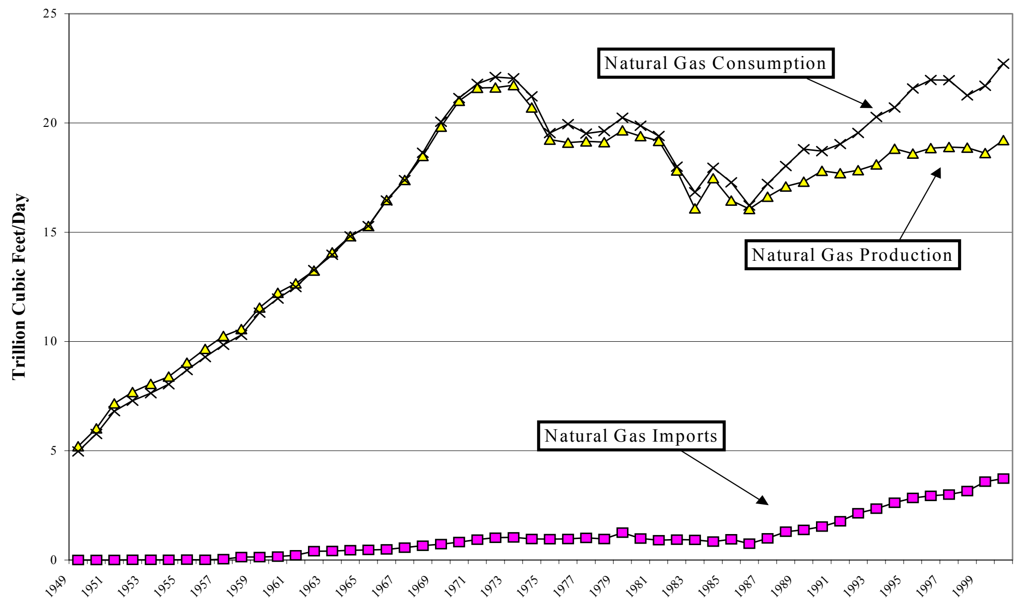
The gradual global shift to natural gas may benefit the U.S. to a degree but it will not change the fact that the U.S. will be a net gas importer. The U.S. is in possession of less than five percent of the world's proven gas reserves. The Former Soviet Union and the Middle East combined control over 65 percent.

Figure 2-8 illustrates the U.S. position regarding production, consumption and imports of natural gas over the past 40 years. Imports over the last 15 years exhibit a strong upward trend and this looks set to continue as consumption continues to outpace domestic production. The EIA forecasts an average annual increase in imports to the U.S. of natural gas of 2.6 percent for the 2000-2020 period. For the same period they forecast an average annual increase in natural gas consumed by the transportation sector of 11.7 percent[10] (from an admittedly very low base). BP currently puts the U.S. R/P ratio for proven natural gas reserves at 9.8 years, which raises the possibility of the U.S. severely depleting its domestic supplies before the decline in world oil production. All of these trends indicate the likelihood of both U.S. and world demand for oil (from conventional or non-conventional sources) for transportation rising through the 2050 time frame, with the U.S. increasingly reliant on imports as it looks to have severely depleted both its oil and gas reserves by that time.

Liquid fuels from natural gas (gas-to-liquid, or GTL) have the physical and chemical properties to substitute for conventional petroleum-based fuels, and will reduce oil, but not total energy imports. It is unclear whether an increased use of GTLs will lead to a more competitive global liquid fuel market. Many of the vast and untapped gas reserves are in the OPEC countries that have gained from oil price manipulation. However the distribution of gas reserves is not so skewed in their favor. Two-thirds of the supergiant (>5 bn barrels) and megagiant (>50 bn barrels) oil fields are in the Middle East, but only 19 of the largest 102 natural gas fields are located there[11].

[10] http://www.eia.doe.gov/oiaf/aeo/aeotab_13.htm
[11] Greene 1999

FIGURE 2-8
U.S. PRODUCTION, CONSUMPTION AND IMPORTS OF NATURAL GAS



In addition, within OPEC, Saudi Arabia has one-third of the oil reserves, while gas is much more evenly distributed. Qatar, with less than 0.5 percent of OPEC's oil, has about 12 percent of its gas. It is not intuitively clear as to whether this more equitable distribution will result in increased output and therefore lower prices. Ownership is still concentrated, so a cartel is possible, but the more equitable distribution makes it more difficult for any one nation to lead. Greene analyses the issue with economic theory and does demonstrate that, *ceteris paribus,* both the price of oil and the monopoly power of the cartel will decline with the introduction of GTLs.

In 1999, California supplied 48 percent of its own demand for crude oil. In the same year, about 530,000 barrels per day were imported from Alaska, and nearly 386,000 barrels per day were imported from foreign sources. The proportion of foreign imports has been rising in recent years, and looks set to continue to do so as in-state and Alaskan deliveries decrease over the next 20 years. By 2012, foreign sources are projected to make up over 50 percent of Californian crude oil supplies[12].

---

12 Fuels Report, California Energy Commission, July 1999.

More than any other state, California has already invested in natural gas power plants. Of the proven U.S. natural gas reserves, only 2.6 percent are in California. At present, California imports about 85 percent of the natural gas it consumes, about 30 percent of it from Canada. EEA's base case Natural Gas projections for California, which go as far as 2020, have California's natural gas production doubling between 2000 and 2020 enabling California to supply more of its own gas as a percentage, at a rate of about 24 percent in 2020. This increase in production is based on the assumption that the production increases predicted for the East Lost Hills reserve are achieved, a matter over which there is some debate. Imports from Canada are projected to rise by 30 percent, while non-U.S. LNG imports are projected to rise from none at present to over 250 bcf in 2020. No forecasts to 2040 or 2050 are available, but the trends suggest a much higher level of imports of both crude and gas to California.

3. RETAIL FUEL PRICES IN 2030 – 2040

Assuming that crude production peaks in the 2030 – 2040 time frame, the cost of alternative transportation fuels without significant supply constraints in that time frame will set market prices for crude derived gasoline and diesel. As noted, these are considerable non-domestic reserves of natural gas. In particular, a very large quantity of gas at remote sites or at locations with no local use, is available to satisfy U.S. energy demand. Gas can be shipped directly to the U.S. in liquefied form (LNG), or used as a feedstock for conversion to methanol or Fischer-Tropsch diesel. The costs of these alternatives could suggest the possible range of prices for crude derived gasoline. The analysis assumes that remote gas has a local (wellhead) value of \$0.50 to \$1.00 per MMBtu in 2030 – 2040. Retail price must include conversion cost, cost of shipping to the U.S., and distribution and retailing costs.

<u>Liquefied natural gas</u> requires cryogenic storage and distribution as its temperature is -260°F. In addition, about 15 percent of the gas energy value is lost in conversion and evaporation loss during transportation. Liquefaction costs are well understood, but distribution and retailing cost are very high currently due to limited economies of scale. Amoco estimates that its current retailing costs for LNG are about 47 cents for GGE. Economies of scale and technology improvements could reduce this cost by 30 percent to about 33 cents. Conversion of gas to liquid form and shipping from remote sites is also quite expensive, at 36 cents per GGE. Distribution to retail outlets by cryogenic containers on trucks also adds to costs. Based on these considerations, EEA estimates retail pre-tax price in the \$1.20 to \$1.40 range per GGE.

<u>Methanol</u> and <u>Fischer-Tropsch diesel</u> from remote natural gas have similar production costs, although transportation and retailing cost of methanol are close to double that of gasoline and diesel due to its low energy content per unit volume. The future full cost of methanol delivered at U.S. ports is well understood and estimated to be in the 40 to 50 cents per gallon (or about 80 to 100 cents per GGE) range. In a market where there is excess supply of methanol,

manufacturers can lower prices in the spot market to 30 cents a gallon (wholesale) at which point they are just recovering variable cost, not fixed cost. Any large-scale use in transportation would require construction of new plants, with associated recovery of capital investment. Distribution and retailing costs are also higher due to the low volumetric energy. Retail pre-tax costs of methanol are in the \$1.15±0.10 (pre-tax) range per GGE of M85, a methanol-gasoline mixture.

The cost of Fischer-Tropsch (F-T) diesel is more difficult to determine. Shell has claimed that Fischer-Tropsch diesel becomes competitive at crude prices of about \$25/bbl., although this may involve some optimism on the part of Shell. The estimate may also reflect the fact that these costs are applicable at the low end of the supply curve, assuming supply from developed site like Qatar and Nigeria. F-T diesel from less developed sites, which may be needed for large scale transportation use, will involve higher capital costs and potentially higher operating costs, so that \$30 to \$35/bbl as a competitive crude price benchmark for high volume supply may be more realistic. On the other hand, some of DOE reports have estimated future F-T diesel costs of lower than \$20/bbl.

The costs of methanol, LNG and F-T diesel (outside of the DOE estimates) all suggest that a potential range of crude prices at which there is substantial competition from alternative liquid fuels from gas is in the \$30 to \$35/bbl range. In this range, the pre-tax cost of gasoline is in the \$1.15 to \$1.35 range. Current state and Federal taxes add about 45 to 50 cents to this value, for gasoline retail prices averaging \$1.60 to \$1.85 (in 2000 dollars) in the 2030 – 2040 time frame, if taxes are unchanged, indexed for inflation. These prices are similar to the average levels experienced last year, suggesting that large increase in crude oil prices are unlikely even after the production of oil peaks. Of course, short-term price spikes could occur.

In this context, the prices of other alternative fuels are unlikely to be competitive. Domestic natural gas will also be supply constrained in 2030 – 2040, so that only imported LNG is a realistic option for large-scale transportation use. CNG could be used in niche markets, and domestic gas has historically been priced at 70 to 75 percent of crude oil cost per unit of energy. Hence, gas cost will be in the \$3.60 to \$4.20 range per MMBtu (or 45 to 53 cents per GGE), if crude prices are in the $30 to $35 per barrel range. Distribution, compression and retailing cost would add 50 to 60 cents per GGE, making total cost in the same range as gasoline (pre-tax), which is very similar to the situation today. However, any large-scale demand from transportation would drive domestic gas prices upward.

Both bio-diesel and corn-based ethanol are unlikely to be price competitive, with pre-tax retail prices in excess of $3.00 for bio-diesel and $1.50 for corn-based ethanol per GGE. However, cellulosic ethanol has the potential to be substantially cheaper, and there are predictions of significant technological advances for the conversion process of cellulosic material to ethanol. Unfortunately, much uncertainty also surrounds these predictions. Estimates from widely accepted studies have ranged from $0.70 to $0.90 per gallon of ethanol at the plant gate. Since ethanol has two-thirds the energy content of gasoline, these values ranges from $1.05 to $1.35 per GGE. Adding distribution and retailing costs suggest a retail price of $1.28 to $1.58 per GGE, so that it could be price competitive with gasoline at the optimistic end of the forecast range. In addition, cellulosic ethanol is supply constrained by the availability of cellulosic material such as agricultural wastes or woody waste, to an estimated 20 billion gallons annually, about six percent of transportation energy consumption. Due to these supply constraints, cellulosic ethanol's most likely use even in the future is as a blendstock, and E10 blends (ten percent ethanol/gasoline) could be popular especially if current tax benefits continue to 2030 – 2040.

Hydrogen is also a potential fuel for fuel cell powered vehicles. Hydrogen is usually derived by electrolysis of water, or by steam reforming of methane. A wide variety of other methods are available including coal gasification, biomass pyrolysis, photovoltaics based electrolysis and concentrated solar energy. Steam methane reforming is by far the lowest cost source of hydrogen while other methods results in hydrogen costs that are 100 to 200 percent higher than methane-reforming, according to a comprehensive study by the National Renewable Energy Laboratory (NREL). These processes are <u>not</u> very energy efficient, and hydrogen has the added disadvantage of requiring significant energy for storage, either a liquid or at high pressures. The high-energy consumption in distribution, dispensing and vehicle storage is a unique feature of hydrogen as a vehicle fuel. While predictions of hydrogen production cost can be under \$1/kg, delivered cost can be in the order of \$3 to \$4 per kg, which translates to a retail price of \$3 to \$4 per GGE, since 1 kg of hydrogen has almost the same energy as one gallon of gasoline.

4. VEHICLE TECHNOLOGY IMPLICATIONS

The preceding analysis provides evidence that gasoline prices are unlikely to be significantly higher than (post-tax) $1.60 to $1.85 a gallon 2030-2040 time frame. A number of alternative transportation fuels that are competitively priced at the retail level could emerge and the four most likely are:

- liquefied natural gas (imported);
- Fischer-Tropsch diesel;
- methanol;
- cellulosic ethanol (in supply limited quantity).

These fuels can be in the same price retail range (pre-tax) as gasoline per unit of energy. It is difficult to say how tax polices can change in the long term, or if current ethanol tax subsides will persist after 30+ years to determine post tax retail prices. Nevertheless, these findings have significant implications for vehicle technology and cost effectiveness.

The following analysis considers four categories of technologies. The first examines conventional technologies where improvements can be classified as evolutionary. The second examines the diesel engine, and the third examines gasoline-electric hybrid vehicles. The final section examines fuel cell powered vehicles of different types. All of these technologies are examined in the context of a world where gasoline prices are in the $1.60 to $1.85 per gallon (retail price) range.

One of the problems with looking at distant time frames is that our technology forecasting ability usually extends to only about 20 to 25 years. While the current internal combustion engine powered vehicle is a “mature” technology, new advances can never be completely ruled out. Among hybrid engine/electric motor technologies, there is the possibility of unexpected advances in power switching and electrical power storage technology that cannot be foreseen today. Hence, to some degree, the scenarios here may represent a fuel economy "floor" in that all of the technologies described here can enter the market by 2020 or 2025. Of course, many are not cost-effective and would not be introduced into the mass market in the absence of a regulatory requirement or a fuel price shock.

4.1 EVOLUTIONARY IMPROVEMENTS

There appears to be little doubt about the ultimate potential of evolutionary improvements to vehicles. Table 4-1 provides a detailed listing of all available evolutionary technology improvements and their cost-effectiveness at $1.70/gallon fuel. The net total improvement from all technologies is in the range of 60 to 70 percent improvement in fuel economy (or a 37.5 to 41 percent decrease in fuel consumption) after accounting for technology interactions, depending on vehicle size and type. About 25 to 30 percent improvement is associated with weight, aerodynamic drag, rolling resistance and accessory power consumption related improvements, while the remaining 35 to 40 percent could be accomplished by improvements to the gasoline engine (making it almost as efficient as a diesel engine) and transmission. Somewhat larger improvements are possible in light trucks than in cars. The net cumulative price effect of this type of reduction is on the order of $2500 to $3500, depending on vehicle size.

For a current midsize car (as an example), the discounted value of fuel cost over a vehicle's lifetime at $1.70/gallon, is about $5000. A 40 percent reduction in fuel consumption will save about $2000, below the total consumer cost of the technologies. Calculations show that at the point where marginal cost equals marginal savings, about half the total F/E improvement (30 to 35 percent) is cost-effective at gasoline prices of $1.70/gallon.

These computations and estimates are all performed at constant vehicle attributes. Over the last 20 years, vehicles have become larger, heavier, more powerful and more luxurious, and these trends are likely to continue if fuel prices rise by only the amount indicated (i.e., by about one percent a year or less) and incomes continue to grow. In the absence of any new fuel economy regulations, it is possible that more than half the fuel economy improvements could be lost to

TABLE 4-1
EVOLUTIONARY TECHNOLOGY IMPROVEMENTS

	F/E Benefit % (Range)	Cost-Effective @ $1.70/Gallon ?
• Weight Reduction		
– advanced HSLA	3 – 4	Yes
– plastic composites	3 – 4	Marginal
– aluminum castings	1.5 – 2	Yes
– light weight interiors	1.5 – 2	Yes
– aluminum closures	1.5 – 2	No
– aluminum structures	3 – 4	No
– carbon fiber structure	3 – 4	No
• Drag Reduction		
– C_D to 0.28*	2 – 2.5	Yes
– C_D to 0.25	1.8 – 2.0	Yes
– C_D to 0.22	1.8 – 2.0	Marginal
• Rolling Resistance		
– C_R to 0.0075	2 – 3	Yes
– C_R to 0.0065	1.5 – 2	Yes
– C_R to 0.0050	1.5 – 2	Not Clear
• S.I. Engine**		
– 4-valves/cylinder	4 – 5	Yes
– variable valve lift/timing	6 – 7	Yes
– cylinder cutout	7 – 8	Yes
– camless valve actuation	2 – 3	No
– variable compression ratio	6 – 7	No
– supercharging	3 – 4	No
– friction reduction	2 – 4	Yes

* For cars, proportional reduction for light trucks.
** assumes a baseline of an overhead cam, 2 valve/cylinder engine.
Note: F/E Benefits are not additive.

TABLE 4-1
EVOLUTIONARY TECHNOLOGY IMPROVEMENTS
(Continued)

	F/E Benefit % (Range)	Cost-Effective @ $1.70/Gallon ?
• Transmissions		
– 5-speed automatics	3 – 4	Marginal
– CVT	5 – 7	Yes
– 6-speed automatic	2 – 3	No
– electrically shifted manual	2 – 3	Not clear
– ‘aggressive’ shift logic	3 – 5	Yes
• Accessories		
– gear driven oil pumps	~0.5	Yes
– electric power steering	2.0 – 2.5	Yes (with 42V)
– electric water pump	~0.5	No
– high efficiency alternator	~0.5	Yes
• Other		
– reduced brake drag	0.5 – 1	Yes
– improved 4WD center differential	1 – 2	Yes

vehicle attribute improvements so that net fuel economy gains in 2030 – 2040 may be only in the 15 to 20 percent range, relative to today.

Non-cost effective technologies include:

- aluminum intensive structures;
- advanced composite structures;
- very low aerodynamic drag shapes;
- camless valve actuation;
- variable compression ratio;
- engine supercharging/downsizing;
- six speed automatic transmissions.

However, it should be noted that when compared with most other 'unconventional' technologies, evolutionary improvements continue to be the lowest cost method to reduce fuel consumption.

4.2 DIESEL ENGINES

The diesel engine, while still a conventional technology, is unconventional only in the U.S. context. In its current form, diesel engines provide a 40 percent fuel economy benefit over an "equal performance" gasoline engine, for a retail price premium for about $1200 for a four-cylinder engine to about $2500 for a V-8 in a large pickup truck. In the short term (to 2010) there is considerable concern about the diesel engine's ability to meet the California "LEV II" emission standards.

Recent technological improvements to diesel engines and emission controls now suggest that diesel engines could meet California emission standards, especially if the rate of technology progress can be sustained. Engine technology improvements include:

- four-valve heads with central fuel injector;
- common rail electronically controlled fuel injection systems;
- variable geometry turbocharging;
- cooled exhaust gas recirculation.

These technologies have already been incorporated into some of the new diesel engines emerging in Europe, but further improvements can be realized. In particular, second-generation common rail fuel injection system suppliers claim further significant emission reduction potential, with such systems reaching commercial production in the next two to three years.

Aftertreatment technology focusing on NO_x and PM emission continues to improve and raise expectations about the potential for meeting LEV II standards. Catalyzed diesel particulate filters (already commercialized by Peugeot in Europe) have demonstrated the capability to reduce PM emissions to almost unmeasurable levels. Selective Catalytic Reduction (SCR) technology has also shown the capability to attain NO_x reduction levels of over 90 percent (cycle average) that will be required to meet LEV II NO_x standards. This technology requires urea to be stored on board the vehicle and replenished periodically. While there is no technical issue with this requirement, the need for an urea distribution and fueling infrastructure is a market related barrier to commercialization.

Another promising avenue is with NO_x adsorber technology, where NO_x is adsorbed during lean air fuel ratio operation, but is desorbed and converted to nitrogen during rich operation. Since diesel engines never operate rich, special operating conditions and post-injection of fuel are required to achieve the necessary conditions for NO_x desorption and reduction. In addition, the NO_x adsorber in easily poisoned by sulfur so that very low sulfur diesel is essential for its use. In this context, F-T diesel has very favorable characteristics in that it can reduce engine-out emissions of NO_x, and also has naturally low (almost zero) sulfur content. While NO_x adsorber technology needs further development to provide adequate NO_x conversion efficiency for meeting LEV II standards, it is considered by EPA to be the most promising path to meet emission goals.

Plasma – assisted lean NO_x catalysts are a third aftertreatment possibility for diesel engines. While interest in this technology declined last year, some critical new advances have made this technology a possible competitor in the future. New innovations include low power consumption plasma generators, and a system of sequenced plasma generators and catalysts.

Efficiency levels of close to 80 percent on the FTP have been attained, but additional developments are required to reach the 90+ percent conversion efficiency to meet LEV II NO_x standards.

Finally, a new type of combustion system called "Homogenous Charge Compression Ignition" is being developed and shows the potential to reduce engine-out PM and NO_x emissions by 70 to 80 percent with little loss in efficiency. Such systems could emerge in 10 to 15 years and provide high fuel economy with low emissions. Such a system could use lower efficiency after treatment systems to reduce cost and meet LEV II standards.

Of course, the cost of emission control will increase the cost of the diesel engine relative to current costs. The costs are expected to be in the $400 to $700 range depending on engine size, which would increase the incremental price of the diesel engine by 30 to 35 percent. Even at these levels, the diesel engine will be cost effective on a lifetime basis, especially if low cost F-T diesel is widely available.

4.3 HYBRID VEHICLES

EEA's earlier analysis for the CEC had identified several types of hybrids. In terms of costs and benefits, they can be grouped into two distinct categories: low voltage (42V) systems and high voltage systems (over 100 volts).

In general, retail prices for high voltage systems in the near-term (2005+) have been estimated by EEA at $4000 to $6000 in volume production, depending on vehicle size, while providing a fuel economy benefit of 40 to 50 percent. (Such systems are not well suited to load hauling applications or mountainous terrain, where high continuous power output from the engine may be required). Studies conducted by EEA for DOE and by ITS-Davis have suggested future cost declines are possible with learning, scale and technology advances. Based on EEA interviews with manufacturers, we believe that learning and technology advances could reduce prices 20 percent per decade so that retail prices could fall by 49 percent by 2035 (i.e., 0.8 *x* 0.8 *x* 0.8).

However, even at these prices, the high voltage systems would not pay for themselves in the 2030 – 2040 time frame, on a lifetime fuel savings basis.

The 42V system is also not cost effective now since EEA estimated its retail price to be in the \$1200 - \$1600 range in volume production in the 2005+ time frame. However, much of the cost is associated with a 42V net and a dual 12V/42V system. If, for example, all vehicles migrate to a single voltage 42V system, the incremental price of mild hybrids is quite low at \$600 to \$700. Cost reductions similar to those for high voltage hybrids are likely in the next three decades to 2035, so that the incremental price of a 42V hybrid could be in the \$300 to \$350 range by 2035. These systems can provide 10 to 12 percent reduction in fuel consumption and have favorable effects on emissions making them cost-effective in this time frame. If California assists with the transition to a 42V net, mild hybrids could become very common or even standard on all vehicles in the 2030+ time frame.

4.4 <u>FUEL CELL VEHICLES</u>

A number of different fuel cell types are being researched for introduction, and the Proton Exchange Membrane (PEM) fuel cell is considered the most advanced for automotive applications. Other types of fuel cells include the Solid Oxide fuel cell and the Direct-Methanol fuel cell, but these cells are not yet at a stage of development where they can be considered as a candidate for automotive propulsion.

While the PEM fuel cell technology has made remarkable advances in the last decade, there are three factors that may limit its future market penetration. First, the current costs assuming volume production are not yet well understood but are believed to be at least <u>one order of magnitude</u> higher than that of an i.c. engine/transmission. The required level of cost reduction to be cost competitive may be difficult even in 2030 – 2040. Second, the PEM fuel cell (and all fuel cells) produce electricity which must be converted to shaft work in an automobile. The cost of a variable speed motor and controller capable of 100 – 200 kW peak output is itself at least as high as the cost of an engine and transmission, even under optimistic forecasts of cost. Lastly, the PEM fuel cell operates on hydrogen, and obtaining a supply of hydrogen requires on-board hydrogen storage, or a reformer that can convert a hydrocarbon fuel to high purity hydrogen. Both options are expensive and the reformer introduces substantial efficiency losses, so that on a net basis, the vehicle is not much more efficient than an advanced technology conventional vehicle.

Analysis by DTI for DOE and Ford has resulted in incremental cost projections (not retail price) for a hydrogen fuel cell powered midsize car in the \$4000 to \$5000 range, while retail prices in volume production will be 60 to 70 percent higher. EEA regards these figures as optimistic but even at these prices, the fuel cell vehicle offers no cost per mile advantage. Its efficiency on hydrogen will be 150 to 200 percent higher per unit of energy than an advanced gasoline engine, but the cost of hydrogen will offset the efficiency advantage. The DTI analysis also showed that a gasoline reformer/fuel cell powered mid-size car would have fuel economy of about 45 to 50 MPG, similar to that of an advanced hybrid vehicle.

The Solid Oxide fuel cell is also making rapid progress and may offer a lower cost solution than the PEM cell. Its main drawback is that it operates at temperatures 700°C, so that it cannot offer quick startup required for an automotive power plant. It has the advantage of being less sensitive to hydrogen fuel quality than the PEM cell, and being potentially lower in cost. However, it does not significantly change the basic lack of cost-effectiveness in a relatively low fuel price environment, in that costs greatly exceed savings from fuel efficiency.

The direct methanol fuel cell (DMFC) is a variant of the PEM cell where methanol instead of hydrogen is used as a fuel. Methanol is the only hydrocarbon fuel that has sufficient reactivity to be a candidate for fuel cell use, and it may fit well with availability of methanol from remote gas at competitive costs. However, at its current state of development, DMFC stacks are potentially ten times as expensive as PEM stacks due to the low reactivity of methanol in comparison to that of hydrogen. The DMFC could make sense by 2030 – 2040, if the pace of development mirrors the development of the hydrogen PEM fuel cell stack. By avoiding the reformer, and hydrogen storage issues, its ultimate potential may be superior to that of the hydrogen PEM cell.

At this point, there is no clear picture of the best choice of fuel cell type and fuel combination, as all combinations look expensive and unlikely to be competitive in a market where fuel prices are only $1.60 to $1.80 per gallon. The conclusions that would emerge from this analysis are:

- it may be premature to develop a hydrogen fueling network for PEM fuel cells vehicles as it appears to offer no advantage in cost per mile;
- fuel cell vehicles are likely to be sold only due to regulatory pressure or subsidies even in the 2030 – 2040 time frame.
- fuel cell vehicles are more likely to succeed for their low emissions rather than for their fuel efficiency.

4.5 FUEL ECONOMY FORECAST AND POTENTIAL

In the 2030 to 2040 time frame, EEA believes that most of the "cost-effective" technologies at gasoline prices of $1.70± 10 cents per gallon will be employed under any scenario, with or without government intervention. This will result in potential fuel economy growth of 30 to 40 percent from evolutionary technology and another 9 to 12 percent from "mild" hybrid (or 42 volt) systems. However, the net increase of 40 to 50 percent will be utilized for fuel economy only under a regulatory scenario. Under other scenarios, it possible that up to half the improvement will be lost to enhanced vehicles attributes of luxury, performance, size and safety. Regardless of the fuel economy scenario, the technology potential will be utilized.

The remaining potential that is unexhausted will include:

- 30 to 40 percent from advanced evolutionary technology;
- 10 to 12 percent from the diesel engine over and above the s.i. engine improvements included in evolutionary technology;
- another 15 to 20 percent from full hybridization.

These three improvement factors are very nearly additive and could result in a total fuel economy improvement of 65±10[13] percent over a likely 2035 percent improvement, albeit at relatively high cost. Load hauling light trucks may not utilize full hybridization and so their fuel economy improvement potential is less.

---

[13] All percent increases are relative to a 2000 baseline.

At this point, it also appears unlikely that a fuel cell vehicle powered by gasoline or methanol will offer any significant fuel economy or cost advantage. Hydrogen fuel cell vehicles could potentially be more efficient per unit of hydrogen energy used but this may not be true if hydrogen production, distribution and retailing energy losses are considered. Hence, fuel cell vehicles may be important from an emissions standpoint but are not likely to significantly change the energy efficiency issues.